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A Royalty Pain in the Gas: What Costs May Be Properly Deducted from a Gas Royalty Interest

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A ROYALTY PAIN IN THE GAS: WHAT COSTS MAY BE PROPERLY DEDUCTED FROM A GAS ROYALTY INTEREST?

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I. INTRODUCTION

In the early days of oil and gas lease operations, the primary objective of exploration and drilling was the discovery of oil.¹ If gas alone was found, it was generally regarded as a major misfortune.² However, as some limited markets for gas developed, provision was made for the lessee to make fixed royalty payments to the lessor on gas production over the course of the lease.³ As the natural gas industry developed and the value of gas increased, it became apparent that the ultimate value of the gas, and the value of the right to extract and sell the gas, could no longer be ascertained as of the time of leasing.⁴ Therefore, the parties to oil and gas leases decided to change their practice of making periodic fixed payments to one of providing for a royalty on gas based on either the volume or the value of the gas produced.⁵

1. 3 EUGENE O. KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 40.1 (1989).

2. *Id.*

3. *Id.*

4. *Id.*

5. KUNTZ, *supra* note 1, § 40.1.

Today, the amount of the gas royalty represents an issue of high contention between the lessor and the lessee.⁶ Litigation on this issue is likely to continue because the royalty owner/working interest owner relationship is inherently fraught with conflict.⁷ This inherent conflict exists because a lessor's reserved royalty is traditionally viewed as being relatively free of up-front risk, while the lessee's interest in the development of the lease is viewed as highly speculative.⁸ Thus, while a lessee is highly conscious of the costs connected with exploration and production, the lessor does not share these concerns since the royalty is generally due on either the gross value or sales price of the gas produced.⁹

The costs which may result in litigation are numerous, but some of the more common ones include such things as compression, dehydration and gathering. Compression costs occur when the reservoir pressure is insufficient to force the natural gas being produced into a pipeline which is itself under pressure. Thus, it becomes necessary to increase the pressure of the gas after it comes to the surface in order for it to be marketable.¹⁰ Dehydration is the process of removing moisture from the gas before it enters the purchaser's pipeline.¹¹ The term gathering refers to the process of collecting the gas at the point of production (the wellhead) and moving it to a collection point for further movement through a pipeline's principal transmission system.¹² The potential for litigation could be greatly reduced if royalty clauses were more detailed and tailored to addressing potential costs such as compression, dehydration, gathering and transportation.¹³ Even though parties to a contract are always free to allocate these costs, too

6. Owen L. Anderson, *Calculating Royalty: "Costs" Subsequent To Production—"Figures Don't Lie But . . ."*, 33 WASHBURN L.J. 591 (1994).

7. *Id.*

8. *Id.*

9. *Id.*

10. *Garman v. Conoco, Inc.*, 886 P.2d 652, 654 n.2 (Colo. 1994) (quoting J. Clayton La Grone, *Calculating the Landowner's Royalty*, 28 ROCKY MTN. MIN. L. INST. 803, 809 (1983)).

11. *TXO Prod. Corp. v. State Comm'r of Land Office*, 903 P.2d 259, 262 (Okla. 1994).

12. *Id.*

13. Anderson, *supra* note 6, at 591.

often these agreements are silent as to the apportionment of expenses that may be incurred after the discovery of the gas.¹⁴

While the drafting of more detailed royalty provisions may settle many of the potential complications with respect to prospective deals, it would have little, if any, effect on the thousands of existing relationships that are already governed by traditional lease forms that may remain in effect for decades.¹⁵ Existing leases could be amended, but this is doubtful because lessees have generally been reluctant to propose any amendments to lessors for fear that lessors will drive harder bargains.¹⁶ Also, lessees believe that most lessors will not bother to identify royalty payment issues or bother to challenge the lessee's royalty calculations even if the lessors identify the issues.¹⁷

Numerous reasons exist as to why a typical gas lease is silent concerning the allocation of costs. Often, the parties, in an attempt to avoid higher legal costs, adopt archaic language from antiquated leases. The problem with this practice is that many of these antiquated leases do not anticipate the problems or complexities of the modern gas industry. A case that dramatizes this point is *Southland Royalty Co. v. Pan American Petroleum Corp.*¹⁸

The royalty clause in the *Southland* case provided as follows:

(1st.) To deliver to the credit of lessor, free of cost, in the pipe line to which they may connect their wells, the equal one-eighth part of all oil produced and saved from the leased premises and 1/8 of the net proceeds of potash and other minerals at the mine.

(2d.) to pay the lessor One Hundred Dollars, each year in advance for the gas from each well where gas only is found, while the same is being used off the premises¹⁹

The lessee eventually had three gas wells and was producing and selling more than one million dollars worth of gas each year. However, the payments were made to the lessor under clause (2), the flat rate

14. *Garman*, 886 P.2d at 657.

15. *Anderson*, *supra* note 6, at 593.

16. *Id.*

17. *Id.*

18. 378 S.W.2d. 50 (Tex. 1964).

19. *Id.* at 52 (italics omitted).

clause, and not clause (1), which provided for one-eighth of the net proceeds.²⁰ Naturally, the lessor brought suit claiming that the royalty should be based on clause (1). "In an opinion that seems justifiable only upon the basis of the inequity of paying three hundred dollars each year for a million dollars worth of gas, the Texas Supreme Court found for the lessors."²¹

It appears that the court, under the guise of the constructional process, tried to relieve what it felt was unjust enrichment of the lessees caused by a lease executed in 1925.²² It seems obvious that the parties had no intent to include gas in clause (1) by the use of the term "other minerals," for at the time that the lease was drawn up in 1925, gas was of little value, but potash and oil had wide markets.²³ The lessors were providing for a share of the value of the minerals that at that time had a market value.²⁴ Had the amendment to clause (1) not been present, the court would have had little alternative but to find for the lessee. Thus, this case represents a prime example of problems that may arise where old lease forms have been adopted or kept in effect for a long period of time.²⁵

Another reason for royalty disputes may be that parties are afraid to participate in detailed negotiations for fear that some intricate point might become a "deal buster." The parties do not want to jeopardize the venture by discussion of what they consider to be potential problems with the deal. They hope, rather naively, that if any disagreements arise down the road, they will be able to work them out amicably.

Ambiguous terms also contribute to some of the problems connected with royalty calculations. Terms such as "at the wellhead" and "market value" appear to mean different things to different people, and their uses may cause confusion as to the true intention of the parties when they entered the lease. Thus, the important question becomes: What costs incurred by the gas lessee may be properly deducted from the lessor's royalty payment when the lease is silent as to the alloca-

20. RICHARD W. HEMINGWAY, *THE LAW OF OIL AND GAS* § 7.1 (2d ed. 1983).

21. *Id.*

22. *Id.*

23. *Id.*

24. HEMINGWAY, *supra* note 20, at § 7.1.

25. *Id.*

tion of costs? That inquiry is the focus of this Note; its objective is to provide some guidance on when an agreement does not adequately address the allocation of costs. This Note will specifically look at the current status of West Virginia law and what the courts must consider in settling disputes concerning the allocation of these costs.

II. DEFINITION OF ESSENTIAL TERMINOLOGY

Before one can undertake any meaningful examination of the existing case law on this subject, there are some concepts and terms of art that require definition. Terminology such as "market price at the well," "market value," and "proceeds" often appear in royalty clauses. The meaning and connotations associated with these concepts and terms is critical in ascertaining how a royalty calculation is to be determined.

For example, royalty clauses which include terms such as "market price at the well" or "price received by the lessee" signal that a royalty return is to be based upon actual sales in the vicinity of the well.²⁶ Whereas, when the terminology used is "market value," a distinction is made between actual sales in the vicinity of the well and market value that can be established by opinion evidence.²⁷ While, in turn, the term "proceeds" means that the royalty return will generally be based upon the aggregate receipts from the sale of the gas products wherever the sales are made.²⁸

A. Market Price

In those cases where the royalty clause looks to a "market price at the well" and where there are comparable sales of similar gas products in the field, such sales will determine the rate at which the royalty is to be computed.²⁹ Market price is proven by actual transactions rather than market value, fair market value, or reasonable worth.³⁰ In other words, price relates to actual sales, while value or worth are based on

26. HEMINGWAY, *supra* note 20, at § 7.4.

27. *Id.*

28. *Id.*

29. *Id.*

30. HEMINGWAY, *supra* note 20, at § 7.4 (footnote omitted).

opinion.³¹ When no market can be shown to exist at the well, the cases have held that the royalty will be determined on the price received at a distant point, less the costs and expenses of transportation.³² "Such costs of transportation will be shared by the lessor, as no duty exists upon the lessee to construct facilities to transport products to a distant market."³³

B. Market Value

As noted above, there is a distinction between clauses that provide for market price and those that provide for royalty calculations based upon market value.³⁴ Market value, as opposed to market price, is determined at the well.³⁵ Value is distinguishable from price on the premise that the price of a product may not necessarily reflect its intrinsic value.³⁶

As mentioned above, market price is based upon actual transactions, whereas market value is established by opinion evidence which is concerned not only with comparable sales, but also with the intrinsic uses of the product or like products.³⁷ However, there are some decisions where market value is treated the same as market price. For instance, where actual sales of gas exist in the field, this will generally indicate that an actual market in the field will be, as a practical matter, conclusive evidence of value.³⁸

In those instances in which no market exists at the mouth of the well, the court may construct a value by subtracting the expenses associated with processing and transportation from gross receipts.³⁹ There-

31. *Id.*

32. *Id.*

33. *Id.* (citing *Vedder Petroleum Corp. v. Lambert Lands Co.*, 122 P.2d 600 (Cal. Ct. App. 1942); *Matzen v. Hugoton Prod. Co.*, 321 P.2d 576, 73 (Kan. 1958); *Reed v. Hackworth*, 287 S.W.2d 912 (Ky. 1950); *Wall v. United Gas Pub. Serv. Co.*, 152 So. 561 (La. 1934); *Johnson v. Jernigan*, 475 P.2d 396 (Okla. 1970); *Freeland v. Sun Oil Co.*, 277 F.2d 154, (5th Cir. 1968), *cert. denied*, 364 U.S. 826, (1960); *LeCuno Oil Co. v. Smith*, 306 S.W.2d 190 (Tex. Civ. App. 1957)).

34. HEMINGWAY, *supra* note 20, at § 7.4.

35. *Id.*

36. *Id.*

37. *Id.*

38. HEMINGWAY, *supra* note 20, at § 7.4.

39. *Id.*

fore, it would appear that even though the computation of royalty based upon market value differs from that of market price, as a practical matter the courts have reached almost identical results in either instance.⁴⁰

C. Proceeds

Royalty formulas can also be based on "proceeds."⁴¹ In these cases, "royalty computation will generally be made on the basis of the aggregate sales price ultimately received from the separate sales of the constituent products less the cost of marketing, transportation, and treatment."⁴²

III. EXISTING CASE LAW

There appears to be no disagreement regarding the general rule that a royalty is an expense free interest which is paid out of production over the life of the lease. "It is free of all costs of development and production, but may share in any costs incurred subsequent to production."⁴³ Thus, the problem does not concern production costs, which are the responsibility of the lessee, but rather the dispute concerns who is responsible for the costs after production and what constitutes these costs. More specifically, the question is at what point does production cease and post-production begin? The answer to this question: It depends.

No consensus exists with regard to the allocation of expenses incurred after the discovery of gas.⁴⁴ Even commentators in the oil and gas field are not in agreement regarding the allocation of post-production costs.⁴⁵ The case law of the oil producing states has developed

40. *Id.*

41. HEMINGWAY, *supra* note 20, at § 7.4.

42. *Id.*

43. *Martin v. Glass*, 571 F. Supp. 1406, 1410 (N.D. Tex. 1983) (citing *Alamo Nat'l Bank of San Antonio v. Hurd*, 485 S.W.2d. 335, 338 (Tex. 1972)).

44. *Garman v. Conoco, Inc.*, 886 P.2d 652, 657 (Colo. 1994) (citing KUNTZ, *supra* note 1, at § 40.5).

45. *Id.* at 658 n.14. (comparing 3 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW § 645.2 ("A royalty or other nonoperating interest in production is usually subject to a proportionate share of the costs incurred subsequent to production where, as is

two different approaches based upon differing views as to when production is established and a royalty interest accrues.⁴⁶

A. *The Reconstruction Approach*

Texas and Louisiana jurisprudence follow the rule that the lessor must bear its proportionate share of the costs incurred after the gas is severed from the wellhead.⁴⁷ In other words, once the gas is severed from the wellhead it is considered to be "produced."⁴⁸ Thus, the lessee's obligation to market is to market at the well.⁴⁹ In computing the market value of the gas at the well for the purposes of royalty, the lessee is entitled to reimbursement for the lessor's proportionate share of the reasonable cost of transporting the gas to market, dehydrating, compressing or otherwise making the gas more suitable for marketing purposes, including extraction costs which are a result of processing.⁵⁰

For instance, in *Martin v. Glass*,⁵¹ insufficient wellhead pressure caused the lessee to install a compressor to move the gas from two producing wells on the leased property into a nearby gathering line for marketing. It was determined that if the gas were not compressed, it could not be marketed, and would either have to be flared (wasted) or the wells would have to be shut in.⁵² The compression charges were deducted from both the royalty interest and the working interests on a proportionate basis.⁵³ The royalty interest owners objected to the deduction, contending that the compression charges were improper and unauthorized and were a violation of the terms and provisions of the lease.⁵⁴

usually the case, the royalty or nonoperating interest is payable 'at the well') with 3 EUGENE O. KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 40.5 ("It is submitted that the acts which constitute production have not ceased until a marketable product has been obtained.")).

46. *Garman*, 886 P.2d at 657.

47. *Id.*

48. *Martin v. Glass*, 571 F. Supp. 1406, 1415 (Tex. 1983) (citing *Lone Star Gas Co. v. Murchison*, 353 S.W.2d 870 (Tex. 1962)).

49. *Id.* at 1412 (quoting 43 Tex. Jur.2d Oil and Gas § 389).

50. *Id.*

51. 571 F. Supp. 1406 (Tex. 1983).

52. *Id.* at 1409.

53. *Id.*

54. *Id.* at 1410.

In this particular case the pertinent parts of the royalty provisions of the lease were as follows: "3. The royalties to be paid by Lessee are: . . . (b) on gas, including casinghead gas or other gaseous substance, produced from said land and sold on or off the premises, one-eighth of the net proceeds at the well received from the sale thereof"⁵⁵ In resolving whether the compression charges were deductible under the lease, the court stated that "it must first be determined where said instrument establishes the point fixing the price."⁵⁶

In applying Texas law, the court held that because of the net-proceeds-at-the-well royalty provision, the royalty interest owners could be charged for their proportionate share of the cost of compression to move the gas from the producing wells into the gathering lines.⁵⁷ The court's decision was based on a finding that gas production had already been obtained from the wells before compression was required.⁵⁸

In *Parker v. TXO Production Corp.*,⁵⁹ a case factually similar to *Martin*, the Texas Court of Appeals held that, absent contrary terms in the lease, compression costs which are required to increase production are not chargeable to the royalty interest owners, but that post-production costs of compressing gas to make it deliverable into a purchaser's pipeline are normally to be borne proportionately by the operator and the royalty interest owners.⁶⁰

Louisiana law concurs with Texas, in that both jurisdictions allow for the lessee to deduct post-production costs when the royalty payment is determined at the "mouth of the well."⁶¹ However, Louisiana differs slightly in that it applies what is called a reconstruction approach in determining market value.⁶² The reconstruction approach begins with the gross proceeds from the sale of the gas and deducts all costs of

55. *Martin*, 571 F. Supp. at 1410

56. *Id.* at 1411.

57. *Wood v. TXO Prod. Corp.*, 854 P.2d 880, 887 (Okla. 1992) (Opala, J., dissenting).

58. *Id.*

59. 716 S.W.2d 644 (Tex. Civ. App. 1986).

60. *Wood*, 854 P.2d at 887.

61. *Merritt v. Southwestern Elec. Power Co.*, 499 So. 2d 210, 214 (La. App. 2 Cir. 1986).

62. *Id.* at 213.

taking the gas from the wellhead (the point of production) to the point of sale.⁶³

In *Merritt v. Southwestern Electric Power Co.*,⁶⁴ the parties stipulated that “[c]ompression of the gas produced from the Lathan Well was, and remains, necessary to maintain a flow pressure in the gathering system in excess of 700 Psig. Without the compression, no gas produced from the Lathan Well could be sold”⁶⁵ With no purchaser or market for the gas at the wellhead because of its low pressure, the gas was useless and had no market value at the wellhead until it could be moved into the gathering line by compression.⁶⁶ In determining whether compression costs were deductible from the gas royalty, the Louisiana court, like the courts in Texas, first examined the lease to ascertain the point at which the royalty clause fixed the price of the gas.⁶⁷

The court held that unless parties to a lease agree otherwise, a lessee can deduct a proportionate share of post-production compression costs from the royalty payments under a market-value-at-the-well provision.⁶⁸ In this particular case, the lease did not either expressly permit or prohibit a deduction for compression costs.⁶⁹ The Louisiana court agreed with the Texas court’s holding in *Martin*, stating that “compression which is necessary for the gas to reach the wellhead is a production cost, but compression that is necessary only to push the gas from a producing well into a pipeline is a post-production cost or marketing cost which is deductible from royalty payments.”⁷⁰ Thus, in Louisiana, unless an express provision to the contrary is found in a lease, the cost of marketing gas once it has been produced, is shared by the lessor and lessee under a market value lease.⁷¹

63. *Id.* (citing *Wall v. United Gas Pub. Serv. Co.*, 152 So. 561 (La. 1934)).

64. 499 So. 2d 210 (La. App. 2 Cir. 1986).

65. *Id.* at 213.

66. *Id.*

67. *Id.*

68. *See Wood*, 854 P.2d at 887.

69. *Id.*

70. *Id.* (footnote omitted).

71. *Merritt*, 499 So. 2d at 214 (citing *Crichton v. Standard Oil Co. of La.*, 150 So. 668 (La. 1933)).

B. *The Implied Duty to Market Theory*

While Texas and Louisiana follow the rule that the lessor must bear its proportionate share of the costs incurred after the gas is severed from the wellhead, other states have adopted a contrary rule which is based on a lessee's implied duty to market gas produced under an oil and gas lease.⁷² The implied duty to market theory obligates the lessee to incur those post-production costs which are necessary to place the gas in a condition acceptable for market.⁷³

Ample authority exists for the general proposition that, in the absence of an express provision in the lease to the contrary, the lessee owes the lessor an implied duty to market the royalty gas produced.⁷⁴ Under the implied duty to market theory, the lessee has a duty to not only get the product to the place of sale in marketable form,⁷⁵ but also to act in good faith and exercise due diligence in the marketing of the gas.⁷⁶

For example, "Kansas has always recognized the duty of the lessee under an oil and gas lease not only to find if there is oil and gas but to use reasonable diligence in finding a market for the product"⁷⁷ Wyoming, which also follows the implied duty to market theory, has even gone so far as to codify the marketability approach.⁷⁸ Even the Federal government requires that a lessee "place residue gas and gas plant products in marketable condition at no cost to the Feder-

72. *Garman v. Conoco, Inc.*, 886 P.2d 652, 658 (Colo. 1994).

73. *Id.*

74. KUNTZ, *supra* note 1, at § 40.5.

75. *Wood*, 854 P.2d at 882.

76. KUNTZ, *supra* note 1, at § 40.5.

77. *Gilmore v. Superior Oil Co.*, 388 P.2d 602, 606 (Kan. 1964) (citing *Buffalo Valley Oil & Gas Co. v. Jones*, 88 P. 537 (Kan. 1907); *Howerton v. Kansas Natural Gas Co.*, 106 P. 47) (Kan. 1910).

78. *Garman*, 886 P.2d at 658, n.16. ("Wyo.Stat. § 30-5-304(a)(vi) (1994 Supp.) provides in pertinent part: 'Costs of production: means all costs incurred for exploration, [and] development . . . operations including, but not limited to . . . gathering, compressing, . . . dehydrating, separating . . . or transporting . . . the gas into the market pipeline. 'Costs of production' does not include the reasonable and actual direct costs associated with transporting . . . the gas from the point of entry into the market pipeline or the processing of gas in a processing plant.'").

al Government . . . unless otherwise provided in the lease agreement."⁷⁹

Arkansas and North Dakota can also be counted among those that follow the marketability approach when the lease is silent with respect to the allocation of post-production costs. In Arkansas, when a lease is silent as to the allocation of post-production costs, a clause that provides for the lessor to receive "proceeds at the well for all gas" is interpreted to mean gross proceeds.⁸⁰ In North Dakota, if the lease does not state otherwise, royalty payments which are based on the percentage of total proceeds received by the lessee, without deduction for costs, are to be paid to the lessor.⁸¹

Although the implied duty to market answers the question of the lessee's duty to absorb all costs involved in the marketing of the gas, it does not address the issue as to which party or parties must bear any added expense which might be incidental to preparing the gas for market.⁸² This difficulty can be avoided by recognizing that there is a difference between those acts which constitute production and those which constitute processing or refining of the substance extracted by production.⁸³ Under most leases, it is understood that the lessee will bear the costs associated with production, but this does not justify imposing on the lessee the costs of refining or processing the product, unless an intention to do so is revealed by the lease.⁸⁴ Once a marketable product has been obtained then production has ceased.⁸⁵ Once the marketable product has been obtained, the costs in improving or transporting the gas should be shared by both the lessee and the lessor.⁸⁶

It is not always easy to determine when a marketable product has been obtained. However, a good rule of thumb is that if there is a commercial market, then a marketable product has been obtained and further processing should be treated as refining to increase the value of

79. 30 C.F.R. § 206.153(i) (1995).

80. *Garman*, 886 P.2d at 658 (citing *Hanna Oil & Gas Co. v. Taylor*, 759 S.W.2d 563, 565 (Ark. 1988)).

81. *Id.* (citing *West v. Alpar Resources, Inc.*, 298 N.W.2d 484, 491 (N.D. 1980)).

82. KUNTZ, *supra* note 1, at § 40.5.

83. *Id.*

84. *Id.*

85. *Id.*

86. KUNTZ, *supra* note 1, at § 40.5.

a marketable product.⁸⁷ Whereas, if no commercial market is available, the lessee's responsibilities theoretically have not ended, and the lessee must still absorb the costs of making the gas marketable.⁸⁸

The Kansas and Arkansas approach, which burdens the lessee with post-production costs, can be traced back to a trilogy of cases: *Gilmore v. Superior Oil Co.*,⁸⁹ *Schupbach v. Continental Oil Co.*,⁹⁰ and *Hanna Oil & Gas Co. v. Taylor*.⁹¹ The Kansas Supreme Court in *Gilmore* held that a lessee has a duty to pay for gas compression expenses which are necessary to make gas marketable, and that those expenses are not deductible from the royalty interest.⁹² The basis for the court's decision was that since the lessee has a duty to market the gas, it necessarily follows that the lessee has the obligation of preparing the gas for market if it is unmerchantable in its natural state.⁹³ Thus, costs involving marketing or preparation for sale are not chargeable to the lessor.⁹⁴ The Kansas court, in *Schupbach*, followed the rationale of *Gilmore* on the general ground that the case scenarios were identical.⁹⁵

The Arkansas Supreme Court in *Hanna* held that when a gas lease contains a proceeds royalty clause, then a lessee may not deduct compression costs from the royalty payments.⁹⁶ According to the Arkansas court, a contract which is silent regarding the apportionment of compression costs, obligates the lessee, rather than the lessor, to bear those post-production expenses.⁹⁷

In *Hanna*, the royalty clause stated that: "Lessee shall pay Lessor one-eighth of the proceeds received by Lessee at the well for all gas . . . produced from the leased premises and sold by Lessee."⁹⁸ The court's rationale that compression costs were nondeductible from

87. *Id.*

88. *Id.*

89. 388 P.2d 602 (Kan. 1964).

90. 394 P.2d 1 (Kan. 1964).

91. 759 S.W.2d 563 (Ark. 1988).

92. *See Wood*, 854 P.2d at 885.

93. *Id.*

94. *Id.*

95. *See id.* at 885 n.14.

96. *See Wood*, 854 P.2d at 885.

97. *Id.* at 886.

98. *Id.* at 885 n.15.

the royalty payment rested on two factors: (1) the court focused on the word "proceeds" and held that based on its common meaning the lessee could not deduct compression costs, and (2) the parties' construction of the agreement was shown by the lessee's conduct in waiting two and one-half years before deducting compression costs.⁹⁹

C. The Reconstruction Approach v. The Implied Duty to Market Theory

The difference in the two approaches can best be illustrated by comparing the Oklahoma case of *Wood v. TXO Production Corp.*¹⁰⁰ with the Texas case of *Martin v. Glass*.¹⁰¹ In the *Martin* decision, the Texas court allowed for the deduction of compression costs from the royalty interest. The pertinent part of the gas royalty provision read: "[t]he royalties to be paid by Lessee are: . . . (b) on gas . . . produced from said land and sold on or off the premises, one-eighth of the net proceeds at the well received from the sale thereof"¹⁰² The facts presented at trial established that the wells involved in the Glass-Martin lease had sufficient pressure to bring the gas to the wellhead or mouth of the well.¹⁰³ The problem was that there was insufficient pressure at the wellhead to enable the gas to flow into the purchaser's gathering lines without compression.¹⁰⁴ According to the court, the gas was useless and had no market value unless it was moved into the gathering lines.¹⁰⁵ The court further stated that because there was no purchaser, or market, for the low pressure gas as it existed in the wellhead there was no market for the gas at the well.¹⁰⁶ Therefore, the court stated "[t]hus, compression being required to market the gas, said charges were post-production costs and as such were properly deductible from nonoperating interests."¹⁰⁷ It appears that the court rationalized that the lessee had fulfilled his duty by obtaining gas capable of

99. *Id.*

100. 854 P.2d 880 (Okla. 1992).

101. 571 F. Supp. 1406 (N.D. Tex. 1983).

102. *Martin*, 571 F. Supp. at 1410.

103. *Id.* at 1415.

104. *Id.* at 1416.

105. *Id.*

106. *Martin*, 571 F. Supp. at 1416.

107. *Id.*

producing in paying quantities, and that the lessee should not have to bear alone the costs of enhancing the product obtained.¹⁰⁸

In contrast, the *Wood* court rejected the view of the Texas court, which makes a distinction between production and post-production costs, holding instead that the lessor must bear its proportionate share of post-production costs.¹⁰⁹ The Oklahoma court was not, based on the facts before it, prepared to require the lessor to bear compression costs as a matter of law where there was no agreement between the lessor and the lessee to share those costs.¹¹⁰ Instead, the court chose to follow the theory that marketing expenses should be included as part of the lessee's operating costs on the basis that without marketing, there is no production in paying quantities.¹¹¹

In *Wood*, the question presented to the court was whether a gas lessee, who was obligated to pay the lessor 3/16 of the market price at the well for the gas sold, was entitled to deduct the cost of compression from the lessor's royalty interest.¹¹² Initially, the wells involved in the lease produced at a pressure sufficient to enter the purchasers' lines without the aid of artificial compression. However, after pressure from the two wells fell below the required pressure for delivery, TXO was forced to set compressors on the leased premises. TXO then subtracted the lessors' proportionate share of the compression costs from the royalty payments due to the lessors for production from the two wells. The lessors sued to recover the withheld compression charges.

TXO argued that without compression, there would be no sale and thus, no royalty for the lessor.¹¹³ The court found this argument unpersuasive and stated that "[t]here are many steps in the production or post-production processes that, if not performed, would result in no sale. The lessee is in a position to provide specifically in its leases that lessors will be required to share in compression costs."¹¹⁴ Thus, the court held that the compression charges were not deductible from the royalty payment because the lessee must bear the costs when compres-

108. See *Wood*, 854 P.2d at 881.

109. *Id.*

110. *Id.*

111. *Id.*

112. *Wood*, 854 P.2d at 880.

113. *Id.* at 881.

114. *Id.*

sion is required in order to market the gas.¹¹⁵ In the view of the Oklahoma court, the implied duty to market meant a duty to get the product to the place of sale in marketable form.¹¹⁶ Therefore, the lessee bore the risk that, in exploring for the gas, the well would be low pressure.¹¹⁷

While there is a split of authority concerning the allocation of these costs, there are some points of agreement. Most courts seem to concur that the expense of transportation to a distant market should not be the exclusive burden of the lessee. Even states such as Kansas, which follows the implied duty to market theory, believe that the costs of transportation to a distant market must be borne proportionately by the lessor. When it comes to transportation costs it appears to be irrelevant whether the formula for computation relates to the mouth of the well or at the ultimate point of sale.¹¹⁸ In *Matzen v. Hugoton Production Co.*,¹¹⁹ the court stated:

It was as much Hugoton's duty to find a market on the leased premises without cost to the plaintiffs as it was to find and produce the gas . . . ; but that duty did not extend to providing a gathering system to transport and process the gas off the leases at a large capital outlay with attending financial hazards in order to obtain a market at which the gas might be sold.¹²⁰

However, the courts do not concur on how to treat the costs of preparation of the products for market that do not necessarily involve capital expenditures, such as the costs of compression, dehydration, and other processes related to preparing the gas for market.

[S]ome courts would charge the lessor with his proportionate share of the costs of dehydration and other preparation for market. Where the royalty clause applies the compensation formula 'at the well,' some courts have approached the question by charging the lessee with all non-extraordinary costs of market preparation. However, an analysis on the basis of the nature of the cost or the place of sale is unsatisfactory.

115. *Id.* at 883.

116. *Wood*, 854 P.2d at 882.

117. *Id.*

118. HEMINGWAY, *supra* note 20, at § 7.4.

119. 321 P.2d 576 (Kan. 1958).

120. HEMINGWAY, *supra* note 20, at § 7.4 (quoting *Matzen v. Hugoton Prod. Co.*, 321 P.2d 576 (Kan. 1958) (citations omitted)).

The better approach would seem to be whether such costs are conceived to be within the implied obligation of the lessee to market the products from the lease. Those cases would charge all such costs to the lessee that they find are within such an implied obligation. On the other hand, the contrary result is justified upon the counter-argument that where the lessee has, by such acts or treatment, given or enhanced the value of the product the lessor should not share in the enhanced value without sharing part of the costs. It cannot be said that any particular view prevails, with the exception that Kansas appears to find the costs chargeable against the lessee only, whereas the opposite view appears to be espoused in Louisiana.¹²¹

IV. ANALYSIS

Considering that West Virginia is a large gas producing state, it is somewhat surprising that an examination of the current status of West Virginia law indicates that the court has not yet addressed the issue of what costs are deductible from a royalty payment when the lease is silent regarding the allocations of costs after the discovery of gas. Thus, West Virginia has yet to decide whether it would follow the implied duty to market theory, like Kansas and Oklahoma, or the theory that gas is considered produced once it is severed from the well-head, which has been adopted in states such as Texas and Louisiana. An inquiry into West Virginia case law may, however, be beneficial in shedding some light on how the court would rule if confronted with this issue. While these cases are not specifically on point, they do offer some insight on how the court views the relationship between the lessor and the lessee.

“In many jurisdictions the word ‘royalty’ has a definite and unambiguous meaning denoting a fractional interest in production, free of costs and expense, which will not share or participate in bonus, delay rentals, or power to lease.”¹²² West Virginia shares this view. In *Davis v. Hardman*,¹²³ the West Virginia Supreme Court of Appeals stated:

121. HEMINGWAY, *supra* note 20, at § 7.4 (footnotes omitted).

122. HEMINGWAY, *supra* note 20, at § 2.7 (footnote omitted).

123. 133 S.E.2d 77 (W. Va. 1963).

The distinguishing characteristics of a non-participating royalty interest are: (1) Such share of production is not chargeable with any of the costs of discovery and production; (2) the owner has no right to do any act or thing to discover and produce the oil and gas; (3) the owner has no right to grant leases; and (4) the owner has no right to receive bonuses or delay rentals. Conversely, the distinguishing characteristics of an interest in minerals in place are: (1) Such interest is not free of costs of discovery and production; (2) the owner has the right to do any and all acts necessary to discover and produce oil and gas; (3) the owner has the right to grant leases, and (4) the owner has the right to receive bonuses and delay rentals.¹²⁴

Like all the other jurisdictions, West Virginia follows the concept that a royalty always presupposes development or production of gas.¹²⁵ It is also well established in West Virginia that "when a lessee under an oil and gas lease produces gas from the well the right to produce such gas becomes a vested right and when the gas is extracted the title to the gas vests in the lessee and the consideration or royalty paid for the privilege of search and production is rent for the leased premises."¹²⁶ The court has also held that in construing a deed or other legal instrument, that it is the function of the court to ascertain the intent of the parties as expressed in the language used by them.¹²⁷

It is this author's belief that when a gas lease is silent regarding the allocation of costs post discovery, the West Virginia court should follow the implied duty to market theory, rather than the view espoused by jurisdictions such as Texas and Louisiana. That is, West Virginia should reject the position that gas is considered produced when severed from the wellhead.

Even though West Virginia has not been directly confronted with an issue that has required it to accept either one of these theories, a reasonable interpretation of how the court views the relationship between the royalty interest owner and the working interest owner tends to show that the court would be more inclined to accept the implied duty to market theory. For example, *Davis v. Hardman* has been inter-

124. *Id.* at 81 (quoting *Mounger v. Pittman*, 108 So. 2d 565 (Miss. 1959)).

125. *McIntosh v. Vail*, 28 S.E.2d 95, 97 (W. Va. 1943).

126. *Breedlove v. Pennzoil Co.*, 399 S.E.2d 187, 191 (W. Va. 1990).

127. *Id.* at 81 (citing *Hall v. Hartley*, 119 S.E.2d 759 (W. Va. 1961); *Stephenson v. Kuntz*, 49 S.E.2d 235 (W. Va. 1948); *Swope v. Pageton Pocahontas Coal Co.*, 41 S.E.2d 691 (W. Va. 1947); *Bruen v. Thaxton*, 28 S.E.2d 59 (W. Va. 1943)).

puted as defining a royalty interest as a grant or reservation creating a non-cost bearing interest that will share in only a fractional portion of the gross production, and will not participate in bonus, delay rentals or the power to lease.¹²⁸ It also seems to indicate the court's recognition of the fact that once the lessor has been granted a royalty interest that he has parted with input into the cost-bearing decisions.

A number of other reasons exist as to why West Virginia should adopt the implied duty to market theory over the theory that the royalty interest owner should share in the costs after the gas is severed from the wellhead. The most compelling reason for opting for the implied duty to market theory, and allocating costs to the lessee, is traceable to the basic difference between the cost bearing interests and the royalty interests.¹²⁹ Even though a lease is entered into for the benefit of both parties, in most instances the parties do not participate equally in gas development decisions.¹³⁰ In most cases the lessor defers to the lessee, who is the risk-bearing party, to decide such things as where and when to drill, the formations to be tested, and ultimately whether to complete a well and establish production.¹³¹ Thus, this relationship between the parties calls for a "free-ride" for the lessor with respect to all costs incurred to establish a marketable product.¹³²

Paying parties, on the other hand, do not have a "free-ride." They do, however, normally have input into the proposed procedures and expenditures, and ultimately have the right to disagree with the course of conduct selected by the lessee.¹³³ Royalty interest owners, however, do not have such rights.¹³⁴ Therefore, the lessor, as the owner of the minerals, grants an oil and gas lease, retaining a smaller interest in exchange for the risk-bearing working interest receiving the lion's share of the proceeds for developing the minerals and bearing the costs thereof.¹³⁵ The mineral owner's decision on whether to lease or to become a working interest owner is based in large part upon the costs

128. HEMINGWAY, *supra* note 20, at § 2.7.

129. *Garman v. Conoco, Inc.*, 886 P.2d 652, 660 (Colo. 1994).

130. *Id.* at 657.

131. *Id.*

132. *Id.*

133. *Garman*, 886 P.2d at 660.

134. *Id.*

135. *Wood*, 854 P.2d at 882.

involved.¹³⁶ Once the royalty owner makes the decision to lease, he forfeits any right to have input into the cost-bearing decisions.¹³⁷ If a royalty owner were required to share in the costs it would in effect force the royalty owner to share in the burdens of the working interest ownership without the attendant rights.¹³⁸

A royalty interest owner should be able to make an informed economic decision whether he wants to enter into an oil and gas lease or whether to participate as a working interest owner.¹³⁹ Therefore, a lessee who wishes for a royalty interest owner to share in such costs as compression, gathering and dehydration should spell it out in the lease.¹⁴⁰ It would not be unreasonable to expect the West Virginia court to adopt this rationale. In *Cole v. Pond Fork Oil & Gas Co.*,¹⁴¹ the court stated:

A lessor of oil and gas parts with all right and control over the production of his property, save and except the right to insist upon protection of the leased property by reasonable development under the lease; but generally speaking, he parts with every vestige of control over the actual production of oil and gas in the property he leases.¹⁴²

Thus, West Virginia, like other jurisdictions, recognizes that the royalty interest owner parts with the control and the risk in return for a smaller economic interest.

Another compelling reason for adopting the implied duty to market theory is that an inequality may not only exist in development decisions, but also in the bargaining position of the parties. Ordinarily the lessor will be an individual landowner who is not well educated in the customs and practices of the gas industry, whereas the lessee will tend to be a large corporation which is better suited to anticipate all the issues and problems that may arise in a gas deal. As a result, the lessor is usually ill-equipped to deal with the more sophisticated lessee when it comes to entering an agreement concerning the exploration of

136. *Id.* at 883.

137. *Id.*

138. *Id.*

139. *Wood*, 854 P.2d at 883.

140. *Id.*

141. 35 S.E.2d 25 (W. Va. 1945).

142. *Id.* at 29.

gas. Therefore, the burden should rest with the lessee in providing for a costs provision clause in the lease that stipulates which costs may be deducted from the royalty payment. By doing so, the lessor would be better able to make an informed economic decision on whether to participate as a risk-bearing party or a non-risk-bearing party.

When the lease fails to provide for the apportionment of costs after the discovery of gas, the rule that the lessee has an implied duty to market the product appears to be more equitable than the rule espoused by Texas and Louisiana that the non-operating interest must bear its proportionate share of costs incurred after gas is severed at the wellhead. The lessee is in the better position to anticipate and provide solutions to any possible costs that may arise. Therefore, it is the lessee that should bear the burden if the lease fails to provide for apportionment of costs after production. The implied duty to market theory puts this burden where it belongs, on the lessee, and not the lessor, as does the contrary rule that gas is produced when severed at the wellhead, and thus, costs are to be shared. Therefore, it would appear that the equitable solution would be to place the burden on the lessee to negotiate a lease which covers all the possible cost scenarios that may arise.

It can be argued that the implied duty to market theory places an undue burden on the lessee when he fails to include a cost provision in the lease.¹⁴³ Some authorities consider this solution to be harsh and untenable because it saddles the lessee with the sole responsibility for adding a cost apportionment clause to the lease and makes the lessee responsible for all post-production costs.¹⁴⁴ However, while this may be true, for the reasons mentioned above, it would seem that equity would require that the lessee bear the responsibility for providing for a cost provision in a lease as opposed to the lessor.

V. CONCLUSION

It should be emphasized that parties contracting for oil and gas leases are always free to allocate the costs of compression, transporta-

143. *Wood*, 854 P.2d at 883.

144. *Id.* (Opala, J., dissenting) (joining Chief Justice Opala were Vice Chief Justice Hodges, and Justices Lavender and Watt).

tion and processing in their agreements, thereby avoiding many of the potential problems discussed herein.¹⁴⁵ However, it must be recognized that all too often lease agreements fail to apportion expenses that may be incurred after the discovery of oil or gas.¹⁴⁶

In the likely event that the West Virginia courts are faced with this issue, they would be wise to adopt the implied duty to market theory, thereby, putting the onus on the lessee to either provide up front in the lease for the apportionment of costs after the discovery of the gas, or in those instances where the lease is silent as to who will incur the cost, to place the burden on the lessee to cover those costs.

These include costs which are incurred for compression, gathering, and dehydration or any other costs which are incurred in an effort to make the gas marketable. As for those costs which are incurred for the purposes of enhancing the value of the gas after a marketable product is obtained, if the lessor is to share in the profits after enhancement of the gas then he should be required to proportionately share in the costs of enhancing the gas.

Regarding transportation costs, even in jurisdictions such as Oklahoma, where the lessee is obligated to develop the gas he has found so that it will bring the highest possible market value, the lessee is not required to provide for pipeline facilities beyond the lease premises.¹⁴⁷ Kansas courts have also held that the lessee has a general duty to see that the gas is marketed, but that it is not required to pay the lessor's share of transportation charges from the well to some distant place.¹⁴⁸

Thus, in West Virginia when a gas lease is silent as to what costs a lessee may properly deduct from a lessor's royalty payment, the lessee should bear the costs under the implied duty to market theory if those costs do not involve enhancing the product or transporting it to some place of sale off the leased premises.

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145. *Garman*, 386 P.2d at 657.

146. *Id.*

147. *Johnson v. Jernigan*, 475 P.2d 396, 399 (Okla. 1970).

148. *Garman*, 386 P.2d at 654 n.1.